NEWS RELEASE

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Enerplus Announces Strong 2015 Results; Low Cost Reserves Additions and Reduced 2016 Budget and Dividend

All financial information contained within this news release has been prepared in accordance with U.S. GAAP. This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial, reserves, contingent resources and operational information in this news release as well as the use of certain financial measures that do not have standard meaning under U.S. GAAP. A full copy of Enerplus' 2015 Financial Statements and MD&A are available on our website at www.enerplus.com, under our profile on SEDAR at www.sedar.com and on the EDGAR website at www.sec.gov.

Calgary, Alberta - Enerplus Corporation ("Enerplus" or the "Company") (TSX: ERF) (NYSE: ERF) is pleased to announce its results for the fourth quarter of 2015 as well as full year 2015 operating, financial and reserves results. Enerplus is also updating its capital budget and production forecast for 2016 and is reducing its monthly dividend.

"Despite the commodity price headwinds in 2015, we delivered an exceptionally strong year of operational performance while maintaining our financial flexibility and continuing to improve the focus of our portfolio," said Ian C. Dundas, President and CEO of Enerplus. *"We continued to focus our capital program on our core position in North Dakota where we delivered 28% production growth during 2015 under a disciplined and paced development strategy. Our ongoing commitment to reducing our cost structure helped us realize operating and G&A costs below our targets and competitive F&D costs at $8.44 per BOE".*

FINANCIAL AND OPERATIONAL HIGHLIGHTS

- Enerplus delivered fourth quarter production of 106,905 BOE per day, contributing to annual average production of 106,524 BOE per day, approximately 3% higher than 2014 and above guidance of 106,000 BOE per day. This strong production was despite a 39% reduction in capital spending year-over-year and over 6,000 BOE per day of production divested during the year which, given the timing of the divestments, reduced annual average volumes by approximately 1,300 BOE per day.
- Crude oil and natural gas liquids production also exceeded guidance, averaging 46,227 barrels per day in the fourth quarter and 46,402 barrels per day in 2015. This represents liquids production growth of approximately 6% over 2014. The higher liquids production is attributed to strong production growth in North Dakota which averaged approximately 27,700 BOE per day during 2015, up 28% from 2014.
- Enerplus exceeded its production targets despite lower than budgeted capital spending of $89 million in the fourth quarter, as a result of continued well outperformance and further cost savings. Full year capital spending was $493 million, below guidance of $510 million. Enerplus allocated 85% of its 2015 capital program to its oil portfolio in North Dakota and the Canadian waterfloods. Enerplus drilled 1.8 net wells and brought 6.2 net wells on-stream in the fourth quarter, and drilled 46 net wells and brought 57 net wells on-stream during the full year 2015.
- Fourth quarter funds flow was $103 million ($0.50 per share), down approximately 15% from the previous quarter primarily as a result of lower commodity prices and production volumes. Full year funds flow was $493 million ($2.39 per share), down approximately 43% primarily due to significantly lower crude oil and

natural gas prices relative to 2014. Commodity hedging helped support funds flow during 2015 with cash gains of $288 million.

- Continued improvement in Enerplus' cost structure resulted in both 2015 operating costs and G&A costs lower than guidance. Fourth quarter and full-year 2015 operating costs of $8.71 per BOE and $8.76 per BOE, were 10% and 5% lower than comparable periods in 2014, respectively. Fourth quarter and full-year 2015 G&A costs of $1.75 per BOE and $2.09 per BOE, were 33% and 6% lower than comparable periods in 2014, respectively. Reduced capital activity and divestments throughout the year resulted in Enerplus rationalizing its operations and reducing its workforce by approximately 20% which, along with ongoing cost savings initiatives, contributed to the lower G&A costs.

- Enerplus reported a net loss of $625 million in the fourth quarter as it incurred non-cash charges including $266 million related to an asset impairment and a $426 million valuation allowance for deferred tax assets. Under U.S. GAAP, Enerplus is required to use twelve month trailing average prices to determine impairment, and consequently the impairment reflects the low commodity prices throughout 2015. Enerplus reported a net loss for the full year of $1,523 million and impairment charges of $1,352 million. Under U.S. GAAP impairments are not reversed in future periods.

- Enerplus continues to maintain its financial flexibility through its ongoing reduction to cost structures, successful non-core asset sales and disciplined capital spending. Enerplus ended the year with total debt net of cash of $1,216 million, including 11% drawn on its $800 million bank credit facility. Year-end debt to funds flow ratio was 2.5 times and debt to EBITDA ratio was 2.2 times.

- In addition to divestments announced during 2015, Enerplus sold various non-core Canadian shallow gas assets located in southern Alberta in the fourth quarter. These were lower margin properties with dry gas production and higher operating costs than Enerplus' corporate average, comprising approximately 2,300 gross shallow gas wells (1,700 net wells). This divestment reduced the Company's Canadian well count by approximately 17%, and reduced its overall abandonment obligations by approximately 15%. The cash consideration for these assets was nominal. Production from these properties was approximately 2,700 BOE per day (99% natural gas). This divestment further improves the focus and concentration of Enerplus' portfolio and is expected to improve the Company's netback as a result of the higher relative operating costs of these assets and have a modest impact on funds flow.

- Subsequent to year-end, Enerplus announced two Deep Basin asset divestments for total proceeds of $193 million. The Company received proceeds of $183 million, before adjustments, on the closing of one sale in January 2016, and expects the second transaction to close during the first quarter of 2016. Proceeds have been used to repay Enerplus' drawn bank credit facility as well as a portion of its outstanding senior notes which has further improved the Company's liquidity position.

SELECTED FINANCIAL AND OPERATING RESULTS

	Three months ended December 31, 2015	Three months ended December 31, 2014	Twelve months ended December 31, 2015	Twelve months ended December 31, 2014
Financial (000's)				
Funds Flow[4]	$102,674	$212,518	$493,101	$859,020
Cash and Stock Dividends	22,717	55,511	131,955	221,098
Net Income/(Loss)	(624,987)	151,652	(1,523,403)	299,076
Debt Outstanding - net of cash	1,216,184	1,134,894	1,216,184	1,134,894
Capital Spending	89,490	180,999	493,403	811,026
Property and Land Acquisitions	8,794	1,305	9,552	18,491
Property Divestments	83,236	17,945	286,614	203,576
Debt to Funds Flow Ratio[4]	2.5x	1.3x	2.5x	1.3x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$0.50	$1.03	$2.39	$4.20
Net Income/(Loss)	(3.03)	0.74	(7.39)	1.46
Weighted Average Number of Shares Outstanding (000's)	206,517	205,519	206,205	204,510
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$23.81	$40.50	$27.07	$49.13
Royalties and Production Taxes	(4.75)	(9.13)	(5.63)	(10.75)
Commodity Derivative Instruments	7.50	4.71	7.40	0.09
Cash Operating Expenses	(8.68)	(9.51)	(8.75)	(9.23)
Transportation Costs	(2.98)	(2.91)	(2.95)	(2.69)
General and Administrative	(1.75)	(2.62)	(2.09)	(2.22)
Cash Share-Based Compensation	0.16	1.40	(0.02)	0.03
Interest, Foreign Exchange and Other Expenses	(2.94)	(1.23)	(2.78)	(1.42)
Current Tax (Expense) / Recovery	0.07	0.67	0.43	(0.12)
Funds Flow	$10.44	$21.88	$12.68	$22.82
Average Daily Production[2]				
Crude Oil (bbls/day)	41,135	42,818	41,639	40,208
Natural Gas Liquids (bbls/day)	5,092	3,487	4,763	3,565
Natural Gas (Mcf/day)	364,065	355,709	360,733	356,142
Total (BOE/day)	106,905	105,591	106,524	103,130
% Crude Oil and Natural Gas Liquids	43%	44%	44%	42%
Average Selling Price[3]				
Crude Oil (per bbl)	$43.04	$69.17	$48.43	$86.28
Natural Gas Liquids (per bbl)	16.61	42.34	18.06	51.72
Natural Gas (per Mcf)	1.89	3.25	2.15	3.94
Net Wells Drilled	2	25	46	88
Average Benchmark Pricing				
WTI crude oil (US$/bbl)	$42.18	$73.15	$48.80	$ 93.00
AECO natural gas – monthly index (CDN$/Mcf)	2.65	4.01	2.77	4.42
AECO natural gas – daily index (CDN$/Mcf)	2.47	3.60	2.69	4.51
NYMEX natural gas – last day (US$/Mcf)	2.27	4.00	2.66	4.41
US/CDN exchange rate	1.34	1.14	1.28	1.10

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes.
(3) Before transportation costs, royalties and commodity derivative instruments.
(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities.

Share Trading Summary	**CDN* – ERF**	**U.S.** - ERF**
For the twelve months ended December 31, 2015	(CDN$)	(US$)
High	$ 16.09	$ 13.16
Low	$ 4.24	$ 3.01
Close	$ 4.75	$ 3.42

* TSX and other Canadian trading data combined.
**NYSE and other U.S. trading data combined.

2015 Dividends per Share

	CDN$	US$[1]
First Quarter Total	$0.27	$0.22
Second Quarter Total	$0.15	$0.12
Third Quarter Total	$0.15	$0.12
Fourth Quarter Total	$0.13	$0.10
Total Year-to-Date	$0.70	$0.56

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

2015 RESERVES HIGHLIGHTS

Enerplus delivered another year of strong reserves results in 2015:

- Replaced 108% of 2015 production, adding 42 MMBOE of proved plus probable ("2P") reserves. Well performance in both North Dakota and the Marcellus continued to exceed the previous forecasts of Enerplus' independent reserves engineers and resulted in significant positive technical revisions.
- Replaced 163% of 2015 crude oil and NGL production, adding 27 MMBOE of 2P crude oil and NGL reserves primarily from North Dakota. Crude oil and NGLs now comprise 51% of 2P reserves.
- 2P finding and development costs ("F&D") decreased by 14% year-over-year to $8.44 per BOE, including future development costs ("FDC"). Enerplus' three-year average 2P F&D is $10.10 per BOE. Proved producing F&D was $11.90 per BOE in 2015.
- Enerplus sold various properties representing 27 MMBOE of 2P reserves at a value of $13.36 per BOE. Total 2P reserves, net of divestments, were 406 MMBOE at year-end 2015, representing a 5% decrease from 2014.
- 2P finding, development and acquisition costs ("FD&A") were $0.25 per BOE including FDC. Enerplus' three-year average 2P FD&A is $7.76 per BOE.
- 2P reserves in North Dakota increased 17%, including positive technical revisions, to 144 MMBOE, at an F&D of $7.60 per BOE. Based on an average operating netback of $18.66 per BOE in 2015, this represents a recycle ratio of 2.5.
- Proved ("1P") reserves continue to comprise a significant proportion of 2P reserves at 68%. Proved producing reserves represent 49% of 2P reserves.
- Strong reserves life index of 12.2 years, up from 10.7 years at year-end 2014, in part due to a lower production forecast given reduced levels of capital spending in the current low commodity price environment.
- Using the December 31, 2015 independent reserves evaluation, the net present value of Enerplus' 2P reserves discounted at 10%, net of debt and asset retirement obligations and including undeveloped acreage value, is estimated to be $11.65 per share.

2016 OUTLOOK

In response to the continued decline in crude oil prices, Enerplus is taking further steps to protect its balance sheet and maintain its financial flexibility. Enerplus' Board of Directors has approved a reduction in the monthly dividend to $0.01 per share from $0.03 per share, effective with the April dividend, payable on April 15, 2016. This reduction reflects the need to rebalance the dividend level in the context of the sustained low commodity price environment.

Enerplus has also reduced its 2016 capital budget a further 43% to $200 million. This represents a 60% reduction from 2015 spending levels. The reduced budget is focused on balance sheet preservation and maximizing the long-term value of the Company's assets. The revised 2016 capital program comprises drilling 25.9 net wells (18.5 in North Dakota, 1.5 in the Marcellus and 6.0 in the Canadian waterfloods) and bringing on-stream 24.2 net wells (13.6 in North Dakota, 4.6 in the Marcellus and 6.0 in the Canadian waterfloods).

Taking into account the reduced capital program, and the approximately 8,000 BOE per day of production divested since Enerplus released its original 2016 guidance, the revised production guidance for 2016 is 90,000 – 94,000 BOE per day. Expected crude oil and natural gas liquids production is modestly lower at 43,000 – 45,000 barrels per day, now representing 48% of total 2016 production at the midpoint (versus 44% previously).

Enerplus' revised 2016 guidance is based on recent forward prices for crude oil and natural gas of US$38.63 per barrel WTI and US$2.43 per Mcf NYMEX respectively. Under these assumptions, Enerplus anticipates an adjusted payout ratio of approximately 120% in 2016; however the Company expects to reduce debt levels during the year using the $193 million of proceeds from its Deep Basin divestments. Additionally, as a result of these divestments, Enerplus expects to record a gain of $145 million in the first quarter of 2016, thereby improving the Company's debt to EBITDA ratio for 2016. Enerplus' debt covenants include a senior debt to EBITDA threshold of 3.5 times for a period of up to six months, after which it drops to 3.0 times. Under the price assumptions noted above, Enerplus does not expect to exceed its debt to EBITDA covenant in 2016. However, if the current commodity price levels persist, Enerplus would expect to begin negotiating covenant amendments with its lenders towards the end of 2016.

"The reduction to our dividend and reduced 2016 budget reflect our focus on maintaining our balance sheet strength and preserving the value of our high quality assets during this period of low commodity prices", said Dundas. "*We are committed to driving further improvement in our operational efficiencies and the sustainability of our business, and are well positioned to manage through this downturn.*"

2016 Updated Guidance	**Target**
Capital expenditures	$200 million
Annual average daily production	90,000 – 94,000 BOE/day
Crude oil & NGL volumes	43,000 – 45,000 bbls/day
Operating expenses	$9.50/BOE
Transportation expenses	$3.30/BOE
Cash G&A expenses	$2.10/BOE
Average royalty and production tax rate	23%

Note: 2016 updated guidance is based on the following assumptions: US$38.63 per barrel WTI, NYMEX natural gas of US$2.43 per Mcf, AECO natural gas at $2.27 per GJ, and US/CDN exchange of 1.4.

2016 Updated Differential/Basis Outlook*	
U.S. Bakken (compared to WTI crude oil)	US$(7.00)/bbl
Marcellus Basis (compared to NYMEX natural gas)	US$(1.00)/Mcf

*Before field transportation costs

HEDGING UPDATE

Enerplus' commodity hedging program will continue to help protect funds flow in 2016. For the first quarter of 2016 we have hedged 17,000 barrels per day of crude oil which represents approximately 55% of our 2016 forecasted net oil production, after royalties. During the second quarter of 2016 we have hedged 11,000 barrels per day, which represents approximately 36% of our 2016 forecasted net oil production, after royalties. For the third and fourth quarters of 2016 we have hedged 8,000 barrels per day which represents approximately 26% of our 2016 forecasted net oil production, after royalties. Protection levels are shown in the table below. Note that for the downside protection collars, when WTI prices settle below the sold put level in any given month, the collars provide protection at approximately US$14 per barrel above WTI index prices.

We have downside protection on approximately 62,500 Mcf per day of our natural gas production for 2016 consisting of a combination of NYMEX swaps and collars. This represents approximately 28% of our forecasted natural gas production after royalties. Note that for the downside protection collars, when NYMEX prices settle below the US$2.50 per Mcf sold put level in any given month, the collars provide protection at approximately US$0.50 per Mcf above NYMEX index prices.

	WTI Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)[1]		
	Jan 1, 2016 – Mar 31, 2016	Apr 1, 2016 – Jun 30, 2016	Jul 1, 2016 – Dec 31, 2016	Jan 1, 2016 – Mar 31, 2016	Apr 1, 2016 – Oct 31, 2016	Nov 1, 2016 – Dec 31, 2016
Downside Protection Swaps						
Sold Swaps	$55.82	$64.28	-	$2.48	$2.53	$2.48
Volume (bbl/d) or (Mcf/d)	9,000	3,000	-	25,000	50,000	25,000
%	29%	10%	-	7%	23%	11%
Downside Protection Collars						
Sold Puts	$50.13	$50.13	$49.78	$2.50	$2.50	$2.50
Volume (bbl/d) or (Mcf/d)	8,000	8,000	8,000	25,000	25,000	25,000
%	26%	26%	26%	11%	11%	11%
Purchased Puts	$64.38	$64.38	$63.98	$3.00	$3.00	$3.00
Volume (bbl/d) or (Mcf/d)	8,000	8,000	8,000	25,000	25,000	25,000
%	26%	26%	26%	11%	11%	11%
Sold Calls	$79.38	$79.38	$79.63	$3.75	$3.75	$3.75
Volume (bbl/d) or (Mcf/d)	8,000	8,000	8,000	25,000	25,000	25,000
%	26%	26%	26%	11%	11%	11%

(1) Based on weighted average price (before premiums), assuming average annual production of 92,000 BOE/day for 2016, less royalties and production taxes of 23% in aggregate.

OPERATIONAL REVIEW

2015 PRODUCTION & CAPITAL SPENDING

Crude Oil & NGLs (bbls/day)	Q4 2015 Average Production	2015 Annual Average Production	2015 Capital Spending ($million)
Canada	15,561	17,162	$115.9
United States	30,666	29,240	$303.5
Total Crude Oil & NGLs (bbls/day)	**46,227**	**46,402**	**$419.4**
Natural Gas (Mcf/day)			
Canada	135,898	136,924	$41.8
United States	228,167	223,809	$32.2
Total Natural Gas (Mcf/day)	**364,065**	**360,733**	**$74.0**
Company Total (BOE/day)	**106,905**	**106,524**	**$493.4**

2015 NET DRILLING ACTIVITY[1]

Crude Oil	Wells Drilled	Wells On-stream	Dry & Abandoned Wells
Canada	18.4	20.5	-
United States	19.1	23.3	-
Total Crude Oil	**37.5**	**43.8**	**-**
Natural Gas			
Canada	4.3	5.9	-
United States	3.8	7.2	-
Total Natural Gas	**8.1**	**13.1**	**-**
Company Total	**45.6**	**56.9**	**-**

(1) Table may not add due to rounding.

North Dakota

North Dakota production averaged 29,600 BOE per day during the fourth quarter of 2015, an 18% increase in production relative to the fourth quarter of 2014. Enerplus spent $302 million in North Dakota in 2015, drilling 19.1 net wells with 23.3 net wells brought on-stream. The Company continues to deliver strong well results from its Fort Berthold position, where it is achieving among the best well performance and capital efficiencies in the basin. The average initial 30-day production rate ("IP30") of its operated on-stream wells in 2015 was over 1,700 BOE per day. Total well costs (drill, complete, tie-in and facilities) continue to trend down, having averaged US$9.4 million in the fourth quarter with current costs closer to US$9.0 million. At year-end 2015, Enerplus had approximately 9 drilled uncompleted ("DUC") wells in North Dakota.

During 2016, the Company plans to reduce activity levels as a result of the continued low crude oil prices. Enerplus is running a single drilling rig and expects to complete fewer wells in 2016 relative to 2015, with capital spending expected to decline by approximately 60% from 2015 levels to $130 million. As a result, Enerplus' DUC well inventory is expected to grow to an estimated 12 at year-end.

Marcellus

Marcellus production averaged 204 MMcf per day during the fourth quarter of 2015, up approximately 4% relative to the fourth quarter of 2014. Strong well performance kept production relatively flat over the year despite low levels of spending and continued production curtailments. Enerplus spent $32 million in the Marcellus in 2015 drilling 3.8 net wells with 7.2 net wells brought on-stream. At year-end 2015, Enerplus had approximately 9 wells pending completion or tie-in.

Enerplus continues to plan for low levels of activity in the Marcellus during 2016, allocating approximately $20 million of capital to the play.

Marcellus basis differentials continued to be relatively wide during 2015 averaging US$1.37 per Mcf below NYMEX. Enerplus expects its realized Marcellus differentials to improve in 2016, partly as a result of securing 30,000 Mcf per day of Tennessee Gas Pipeline capacity that delivers to a market that prices closer to NYMEX, for US$0.63 per Mcf of firm demand tolls, effective August 1, 2016. As well, the lower levels of industry spending in the region, combined with industry production curtailment at prevailing low NYMEX prices and the continued build out of regional takeaway capacity, are all expected to improve regional pricing. Enerplus is guiding to a basis differential of US$1.00 per Mcf below NYMEX for our 2016 Marcellus production. Despite the improving basis differential, Enerplus is still forecasting some production curtailment due to low NYMEX prices, particularly in the first half of the year.

Canadian Crude Oil

Production from the Canadian waterflood portfolio averaged 17,400 BOE per day during the fourth quarter of 2015, a decrease of 11% from the fourth quarter of 2014. The decrease is largely a result of divesting the Pembina asset during the first quarter, along with some asset declines. Capital spending in 2015 of $116 million was predominately directed to the Brooks drilling program and the Medicine Hat Glauc 'C' ("MHGC") polymer project.

Enerplus expects to invest $50 million in its Canadian oil portfolio in 2016, which will be directed toward waterflood development and optimization activities.

INDEPENDENT RESERVES EVALUATION

All reserves information, including Enerplus' U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") standards. Independent reserves evaluations have been conducted on approximately 84% of the total proved plus probable net present value of future net revenue (before tax, discounted at 10%) of Enerplus' reserves at December 31, 2015. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 45% of Enerplus' Canadian total proved plus probable net present value of future net revenue (before tax, discounted at 10%) and all of Enerplus' U.S. oil assets. McDaniel also reviewed the internal evaluation completed by Enerplus on the remaining 55% of the total proved plus probable net present value of future net revenue (before tax, discounted at 10%) of Enerplus' Canadian assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated all of Enerplus' U.S. natural gas assets.

The following information sets out Enerplus' gross reserves volumes at December 31, 2015 by product type and reserves category under McDaniel's January 1, 2016 forecast price scenarios. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit associated with a property. It should be noted that tables may not add due to rounding.

Subsequent to December 31, 2015, Enerplus entered into two separate agreements to divest of certain Canadian natural gas assets located in the Ansell area. Proved plus probable reserves associated with the two Ansell divestments are 93.4 BcfGE.

The following tables set forth the estimated gross and net reserves volumes and net present value of future net revenue attributable to the Company's reserves at December 31, 2015, using forecast price and costs.

Reserves Summary

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Gross								
Proved producing	13,551	25,894	49,820	89,265	7,310	156,515	463,425	199,898
Proved developed non-producing	62	12	4,696	4,770	423	5,212	19,065	9,239
Proved undeveloped	258	5,799	31,686	37,743	2,972	21,838	142,591	68,120
Total proved	13,871	31,705	86,202	131,778	10,704	183,564	625,081	277,255
Total probable	3,367	9,804	45,051	58,222	4,993	53,802	338,288	128,563
Proved plus Probable	**17,238**	**41,508**	**131,253**	**189,999**	**15,697**	**237,366**	**963,368**	**405,818**
Net								
Proved producing	11,832	21,164	40,222	73,218	5,812	149,537	372,288	166,001
Proved developed non-producing	56	11	3,778	3,845	337	3,885	15,296	7,380
Proved undeveloped	247	4,469	25,404	30,120	2,380	20,345	114,366	54,951
Total proved	12,135	25,644	69,405	107,184	8,528	173,767	501,951	228,331
Total probable	2,845	7,619	36,222	46,686	3,949	50,265	271,689	104,293
Proved plus Probable	**14,980**	**33,264**	**105,626**	**153,870**	**12,477**	**224,032**	**773,639**	**332,625**

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2014 to December 31, 2015.

Due to changes in NI 51-101 product definitions effective July 1, 2015, 5,063 MMcf of proved reserves, 1,709 MMcf of probable reserves and 6,773 MMcf of proved plus probable reserves were moved from the December 31, 2014 Canadian Conventional Natural Gas opening volumes to the Shale Gas opening volumes.

In the U.S., 68,914 Mbbls of proved reserves, 52,631 Mbbls of probable reserves and 121,545 Mbbls of proved plus probable reserves were moved from the December 31, 2014 Light & Medium Oil opening volumes to the Tight Oil opening volumes.

Also in the U.S., 61,048 MMcf of proved reserves, 35,362 MMcf of probable reserves and 96,410 MMcf of proved plus probable reserves were moved from the December 31, 2014 Conventional Natural Gas opening volumes to the Shale Gas opening volumes.

Proved Reserves - Gross Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2014	26,571	31,522	-	58,093	4,333	265,598	5,063	107,535
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(12,183)	(7)	-	(12,190)	(844)	(37,138)	-	(19,224)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	100	1,413	-	1,513	16	1,538	-	1,784
Economic factors	(229)	(1,767)	-	(1,996)	(194)	(23,302)	(32)	(6,079)
Technical revisions	1,982	3,692	-	5,674	626	24,304	(480)	10,270
Production	(2,370)	(3,148)	-	(5,518)	(661)	(47,435)	(402)	(14,151)
Proved Reserves at Dec. 31, 2015	**13,871**	**31,705**	**-**	**45,576**	**3,274**	**183,564**	**4,149**	**80,135**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2014	-	-	68,914	68,914	3,804	-	625,630	176,990
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	(313)	(313)	(17)	-	(148)	(354)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	-	-	5,594	5,594	469	-	23,394	9,962
Economic factors	-	-	(1,173)	(1,173)	(95)	-	(6,722)	(2,388)
Technical revisions	-	-	22,803	22,803	4,275	-	60,386	37,142
Production	-	-	(9,623)	(9,623)	(1,007)	-	(81,609)	(24,231)
Proved Reserves at Dec. 31, 2015	**-**	**-**	**86,202**	**86,202**	**7,430**	**-**	**620,932**	**197,120**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2014	26,571	31,522	68,914	127,007	8,137	265,598	630,694	284,525
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(12,183)	(7)	(313)	(12,503)	(861)	(37,138)	(148)	(19,578)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	100	1,413	5,594	7,107	485	1,538	23,394	11,746
Economic factors	(229)	(1,767)	(1,173)	(3,169)	(289)	(23,302)	(6,754)	(8,467)
Technical revisions	1,982	3,692	22,803	28,477	4,900	24,304	59,906	47,412
Production	(2,370)	(3,148)	(9,623)	(15,141)	(1,667)	(47,435)	(82,011)	(38,382)
Proved Reserves at Dec. 31, 2015	**13,871**	**31,705**	**86,202**	**131,778**	**10,704**	**183,564**	**625,081**	**277,255**

Probable Reserves - Gross Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2014	9,177	11,616	-	20,793	1,330	87,649	1,709	37,016
Acquisitions	-	-	-	-	-	-	-	
Dispositions	(4,253)	(3)	-	(4,256)	(336)	(14,382)	-	(6,988)
Discoveries	-	-	-	-	-	-	-	
Extensions & improved recovery	41	564	-	605	5	519	-	697
Economic factors	120	450	-	570	(58)	(2,777)	(16)	46
Technical revisions	(1,719)	(2,824)	-	(4,543)	8	(17,207)	(164)	(7,430)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2015	**3,367**	**9,804**	**-**	**13,171**	**949**	**53,802**	**1,530**	**23,342**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2014	-	-	52,631	52,631	3,332	-	310,720	107,749
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	(126)	(126)	(8)	-	(63)	(144)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	-	-	7,616	7,616	680	-	43,650	15,571
Economic factors	-	-	86	86	15	-	2,621	538
Technical revisions	-	-	(15,156)	(15,156)	25	-	(20,170)	(18,492)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2015	**-**	**-**	**45,051**	**45,051**	**4,044**	**-**	**336,758**	**105,221**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2014	9,177	11,616	52,631	73,424	4,662	87,649	312,429	144,766
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(4,253)	(3)	(126)	(4,382)	(344)	(14,382)	(63)	(7,132)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	41	564	7,616	8,221	685	519	43,650	16,268
Economic factors	120	450	86	656	(43)	(2,777)	2,606	584
Technical revisions	(1,719)	(2,824)	(15,156)	(19,699)	33	(17,207)	(20,334)	(25,923)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2015	**3,367**	**9,804**	**45,051**	**58,222**	**4,993**	**53,802**	**338,287**	**128,563**

Proved Plus Probable Reserves - Gross Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2014	35,748	43,138	-	78,886	5,662	353,247	6,773	144,552
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(16,436)	(9)	-	(16,445)	(1,180)	(51,520)	-	(26,212)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	141	1,977	-	2,118	21	2,057	-	2,482
Economic factors	(109)	(1,317)	-	(1,426)	(252)	(26,080)	(48)	(6,033)
Technical revisions	263	868	-	1,131	633	7,097	(644)	2,840
Production	(2,370)	(3,148)	-	(5,518)	(661)	(47,435)	(402)	(14,151)
Proved Plus Probable Reserves at Dec. 31, 2015	**17,238**	**41,508**	**-**	**58,746**	**4,223**	**237,366**	**5,678**	**103,477**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2014	-	-	121,545	121,545	7,136	-	936,350	284,739
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	(439)	(439)	(24)	-	(211)	(499)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	-	-	13,210	13,210	1,149	-	67,044	25,532
Economic factors	-	-	(1,087)	(1,087)	(80)	-	(4,100)	(1,850)
Technical revisions	-	-	7,647	7,647	4,300	-	40,216	18,650
Production	-	-	(9,623)	(9,623)	(1,007)	-	(81,609)	(24,231)
Proved Plus Probable Reserves at Dec. 31, 2015	**-**	**-**	**131,253**	**131,253**	**11,474**	**-**	**957,690**	**302,341**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2014	35,748	43,138	121,545	200,431	12,798	353,247	943,123	429,291
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(16,436)	(9)	(439)	(16,884)	(1,205)	(51,520)	(211)	(26,710)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	141	1,977	13,210	15,328	1,170	2,057	67,044	28,014
Economic factors	(109)	(1,317)	(1,087)	(2,513)	(332)	(26,080)	(4,148)	(7,883)
Technical revisions	263	868	7,647	8,778	4,933	7,097	39,572	21,489
Production	(2,370)	(3,148)	(9,623)	(15,141)	(1,667)	(47,435)	(82,011)	(38,382)
Proved Plus Probable Reserves at Dec. 31, 2015	**17,238**	**41,508**	**131,253**	**189,999**	**15,697**	**237,366**	**963,368**	**405,818**

Future Development Costs

Changes in forecast FDC occur annually as a result of development activities, acquisition and divestment activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved and proved plus probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development costs generally reflect the total finding and development costs related to reserves additions for that year.

The following is a summary of the independent reserves evaluators' estimated FDC required to bring the total proved and proved plus probable reserves on production:

Future Development Costs	**Proved Reserves**	**Proved Plus Probable Reserves**
($ millions)		
2016	321	351
2017	409	451
2018	358	479
2019	24	295
2020	8	122
Remainder	25	25
Total FDC Undiscounted	1,145	1,723
Total FDC Discounted at 10%	986	1,417

F&D AND FD&A COSTS – *including future development costs*

($ millions except for per BOE amounts)	**2015**	**2014**	**2013**	**3 Year**
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$493.4	$811.0	$681.4	$1,985.9
Net change in Future Development Costs	($142.2)	($71.3)	$200.0	($13.5)
Gross Reserves additions (MMBOE)	41.6	75.5	78.1	195.3
F&D costs ($/BOE)	**$8.44**	**$9.80**	**$11.28**	**$10.10**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$216.2	$625.9	$561.1	$1,403.3
Net change in Future Development Costs	$(212.5)	$(59.2)	$216.6	$(55.2)
Gross Reserves additions (MMBOE)	14.9	65.8	93.0	173.7
FD&A costs ($/BOE)	**$0.25**	**$8.62**	**$8.36**	**$7.76**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$493.4	$811.0	$681.4	$1,985.9
Net change in Future Development Costs	$210.0	$13.8	$(106.4)	$117.4
Gross Reserves additions (MMBOE)	50.7	69.1	57.1	176.9
F&D costs ($/BOE)	**$13.88**	**$11.94**	**$10.08**	**$11.89**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$216.2	$625.9	$561.1	$1,403.3
Net change in Future Development Costs	$139.7	$4.9	$(112.8)	$31.8
Gross Reserves additions (MMBOE)	31.1	60.9	69.9	161.9
FD&A costs ($/BOE)	**$11.44**	**$10.36**	**$6.41**	**$8.86**

Forecast Price Assumptions

The estimated reserves volumes and the net present value ("NPV") of future net revenues at December 31, 2015 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2016. These prices were applied to the reserves evaluated by McDaniel and NSAI, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below.

McDaniel January 2016 Forecast Price Assumptions

	WTI Crude Oil[1] US$/bbl	Light Crude Oil[2] Edmonton CDN$/bbl	Alberta Heavy Crude Oil[3] CDN$/bbl	Henry Hub Gas Price US$/MMBtu	Natural Gas Alberta Spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$
2016	45.00	56.60	40.50	2.50	2.70	0.730
2017	53.60	66.40	47.50	2.95	3.20	0.750
2018	62.40	72.80	52.10	3.40	3.55	0.800
2019	69.00	80.90	57.80	3.70	3.85	0.800
2020	73.10	83.20	59.50	3.90	3.95	0.825
Thereafter	(4)	(4)	(4)	(4)	(4)	0.825

(1) West Texas Intermediate at Cushing, Oklahoma 40 degree API / 0.5% Sulphur.
(2) Edmonton Light Sweet 40 degree API, 0.3% Sulphur.
(3) Heavy Crude Oil 12 degree API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Escalation is approximately 5% per year until 2023 and approximately 2% per year thereafter.

Net Present Value of Future Production Revenue

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, before income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

Net Present Value of Future Production Revenue – Forecast Prices and Costs *(before tax)*

Reserves at December 31, 2015, ($ Millions, discounted at)	0%	5%	10%	15%
Proved developed producing	$4,116	$2,759	$2,051	$1,634
Proved developed non-producing	$151	$64	$26	$6
Proved undeveloped	$1,314	$573	$233	$55
Total Proved	**$5,580**	**$3,397**	**$2,310**	**$1,695**
Probable	$3,879	$1,938	$1,153	$773
Total Proved Plus Probable Reserves (before tax)	**$9,459**	**$5,335**	**$3,463**	**$2,468**

Net Asset Value

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from its reserves, before taxes, as estimated by the Company's independent reserves engineers, McDaniel and NSAI, at year-end, plus the estimated value of Enerplus' undeveloped acreage, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of contingent resources. As Enerplus executes its capital programs, the Company expects to convert contingent resources to reserves which could result in a significant increase in booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value – Forecast Prices and Costs *(before tax)*

($ millions except share amounts, discounted at)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$9,459	$5,335	$3,463	$2,468
Undeveloped acreage (2015 Year End) (1)	$268	$268	$268	$268
Asset retirement obligations(2)	($206)	($165)	($70)	($38)
Long-term debt, including current portion (net of cash)	($1,217)	($1,217)	($1,217)	($1,217)
Net working capital(4)	($37)	($37)	($37)	($37)
Net Asset Value	**$8,267**	**$4,184**	**$2,407**	**$1,444**
Net Asset Value per Share(3)	**$40.03**	**$20.26**	**$11.65**	**$6.99**

(1) Canadian acreage in Stacked Mannville is carried at market price; validated Duvernay acreage is carried at acquisition cost. Prospective acreage in the U.S. is carried at historical acquisition cost. All other acreage is valued at a nominal value of $50/acre. U.S. values were converted to Canadian dollars using a US/CDN exchange rate of 1.3840.
(2) Asset retirement obligations ("ARO") may not equal the balance sheet as a portion of ARO costs are already reflected in the present value of 2P reserves and the discount rates applied may differ.
(3) Based on 206,539,000 shares outstanding as at December 31, 2015.
(4) Net working capital includes deferred income tax assets and deferred financial assets and credits.

Contingent Resources

The following table provides a breakdown of the economic, unrisked best estimate economic contingent resources associated with a portion of Enerplus' Fort Berthold, Marcellus, Wilrich and Canadian waterflood assets as at December 31, 2015. These contingent resources are economic using McDaniel's January 1, 2016 forecast commodity prices, use established technologies and are all classified in the "development pending" maturity sub-class.

The evaluations of contingent resources associated with the Wilrich, a portion of Enerplus' waterflood properties and leases at Fort Berthold were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of Enerplus' Marcellus shale gas assets in the U.S., including the estimate of contingent resources. There is uncertainty that it will be commercially viable to produce any portion of the resources.

Subsequent to December 31, 2015, Enerplus entered into two separate agreements to divest of certain Canadian natural gas assets located in the Ansell area. Unrisked best estimate economic contingent resources and related net drilling locations associated with the two Ansell divestments are 319.7 BcfGE and 66.3 respectively.

Please see Enerplus' Annual Information Form ("AIF") – Appendix A for additional disclosures related to Enerplus' contingent resources as at December 31, 2015. The AIF is available at www.enerplus.com as well as on the Company's SEDAR profile at www.sedar.com.

Development Pending Contingent Resources	Unrisked "Best Estimate" Contingent Resources	Contingent Resources Net Drilling Locations
Canada		
Waterfloods – IOR/EOR on a portion of waterfloods (MMBOE)	34.7	62.9
Wilrich - Conventional natural gas (BcfGE)	319.7	66.3
Total Canada (MMBOE)	**88.0**	**129.1**
United States Properties		
Fort Berthold – Bakken/Three Forks Tight Oil wells (MMBOE)	96.9	152.2
Marcellus - Shale gas (Bcf)	803.1	95.0
Total United States (MMBOE)	**230.7**	**247.2**
Total Company (MMBOE)	**318.7**	**376.3**

LIVE CONFERENCE CALL

Enerplus plans to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 19, 2016 at 9:00 a.m. MT (11:00 a.m. ET) to discuss these results. Details of the conference call are as follows:

Date: Friday, February 19, 2016
Time: 9:00 am MT/11:00 am ET
Dial-In: 647-427-7450
1-888-231-8191
Audiocast: http://event.on24.com/r.htm?e=1121128&s=1&k=BCAC69207D022B64E7A1C5EE106EE162

To ensure timely participation in the conference call, callers are encouraged to dial in 15 minutes prior to the start time to register for the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Dial-In: 416-849-0833
1-855-859-2056 (toll free)
Passcode: 30573234

Electronic copies of our 2015 year-end MD&A and Financial Statements, along with other public information including investor presentations, are available on our website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

Follow @EnerplusCorp on Twitter at https://twitter.com/EnerplusCorp.

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION

Currency and Accounting Principles

All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent), "MBOE" (one thousand barrels of oil equivalent), "MMBOE" (one million barrels of oil equivalent) and "BcfGE" (one billion cubic feet of natural gas equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs and when converting oil and NGLs to BcfGEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Presentation of Production and Reserves Information

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under IFRS and Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. In order to continue to be comparable with Enerplus' Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis.

*All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "gross reserves" using forecast prices and costs. "Gross reserves" (as defined in NI 51-101), being Enerplus' working interest before deduction of any royalties. Enerplus' oil and gas reserves statement for the year ended December 31, 2015, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form for the year ended December 31, 2015 ("**our AIF**") which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.*

Contingent Resources Estimates

*This news release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as ultimate recovery rates, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. All of our contingent resources estimates are economic using established technologies and based on McDaniel's January 1, 2016 forecast prices. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for these resources to be classified as reserves at this time. There is uncertainty that Enerplus will produce any portion of the volumes currently classified as "contingent resources". "Development pending contingent resources" refer to a "contingent resources" sub-class for a particular project where resolution of the final conditions for development are being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe. The "contingent resources" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2015. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.*

For additional information regarding the primary contingencies which currently prevent the classification of Enerplus' disclosed "contingent resources" associated with Enerplus' Marcellus shale gas properties, Enerplus' Fort Berthold properties, Enerplus' Wilrich natural gas properties and a portion of Enerplus' Canadian crude oil properties as reserves and the positive and negative factors relevant to the "contingent resources" estimates, see Appendix A to Enerplus' AIF, a copy of which is available under Enerplus' SEDAR profile at www.sedar.com, and Enerplus' Form 40-F, a copy of which is available under Enerplus' EDGAR profile at www.sec.gov.

F&D and FD&A Costs

F&D costs presented in this news release are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year.

FD&A costs presented in this news release are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year.

See "Non-GAAP Measures" below.

NOTICE TO U.S. READERS

*The oil and natural gas reserves information contained in this news release has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. Reserves categories such as "proved reserves" and "probable reserves" may be defined differently under Canadian requirements than the definitions contained in the United States Securities and Exchange Commission (the "**SEC**") rules. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above with respect to production information, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Canadian disclosure requirements require that forecasted commodity prices be used for reserves evaluations, while the SEC mandates the use of an average of first day of the month price for the 12 months prior to the end of the reporting period. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings,* *whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "Contingent Resources Estimates" above.*

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected 2016 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management programs in 2016 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2016, debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes.

The forward-looking information contained in this news release reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our 2016 guidance contained in this news release is based on the following: WTI price of US$38.63 per barrel, a NYMEX gas price of US$2.43 per Mcf, an AECO gas price of $2.27 per GJ and a US$/CDN exchange rate of 1.4. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further decline of commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in Enerplus' MD&A and in our other public filings).

NON-GAAP MEASURES

In this news release, Enerplus uses the terms "funds flow", "debt to EBITDA", "adjusted payout ratio" and "netback" as measures to analyze operating performance, leverage and liquidity. "Funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Debt to EBITDA" is calculated as total debt net of cash, divided by trailing 12 months earnings before interest, tax, depreciation and amortization and other non-cash charges. "Adjusted payout ratio" is calculated as cash dividends to shareholders, net of our stock dividends, plus capital spending (including office capital) divided by funds flow. "Netback" is calculated as oil and gas revenues after deducting royalties, operating costs and transportation expenses.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "funds flow", "adjusted payout ratio" and "netback" are useful supplemental measures as they provide an indication of the *results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S.GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' 2015 MD&A.*

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation